

Washington Electric Utility Service Quality, Reliability, Disclosure and Cost Report

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by

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Washington State Auditor

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INTRODUCTION

E2SHB 2831, Chapter 287 of the Laws of Washington, 1998, is titled: *Requiring electric utilities to unbundle the costs of their assets and operations*. This legislation requires certain large Washington State electrical utilities to report information to the Office of the State Auditor (Auditor) and the Washington Utilities and Transportation Commission (Commission). The bill instructs those two agencies to summarize and analyze the information provided, and to report on it to the legislature by December 1, 1998. This report was prepared to meet those requirements. In it the Auditor and the Commission provide four chapters of information that correspond to the four tasks assigned to us by the legislature. This report is based upon the requirements of E2SHB 2831. We will refer to the bill in this report as “2831” or “the legislation.”

Section 1 of the legislation provides several definitions. The terms defined are used throughout this report, so the definitions are provided in endnote one.¹

Chapter one of this report summarizes and discusses the Customer Satisfaction surveys done by the electric utilities. Subsections(2)(4)(a) and (b) of the bill require:

- (4) The service quality and reliability report required of each electric utility under subsection (1) of this section shall include, to the extent such data are currently collected and reasonably available, the following information:*
 - (a) The level of satisfaction of the utility's customers as measured by customer surveys;*
 - (b) The number of customer complaints filed during a calendar year with the commission if the utility is an electrical company or with the governing body if the utility is a consumer-owned utility;*

If available, the report shall include a copy of the survey instrument or script used to collect the information described in (a) of this subsection.

To decrease the burden on reporting electric utilities, in this section the legislation only required data to be provided if the electrical utilities had it available. For this reason, the data available varies widely from company to company. In some instances, the questions that were responsive to the legislative inquiry were sorted from broader surveys in which more proprietary inquiries were also made. The results are summarized, and certain issues are highlighted.

Chapter two of this report summarizes and discusses the Reliability Reports done by the electric utilities. Subsections(2)(4)(c) and (d) of the bill require:

- (4) The service quality and reliability report required of each electric utility under subsection (1) of this section shall include, to the extent such data are currently collected and reasonably available, the following information:*
 - (c) The number of minutes the average customer or feeder line is without electricity during a calendar year; and*

(d) The number of times the average customer or feeder line is without power during a calendar year.

The System Average Interruption *Duration* Index, or SAIDI, measuring minutes of interruption and the System Average Interruption *Frequency* Index or, SAIFI, measuring times of interruption were reported by all electric utilities, with one exception.

Chapter three of this report discusses information disclosure issues. Subsection 3, (2) (e) of the bill requires:

(e) An examination of alternative formats for simple, standardized disclosure of fuel mix, air emission, and other environmental impacts of coal, hydroelectric, natural gas, nuclear, wind, and other generating resources, including the approaches used by utilities that have offered pilot programs to their customers allowing market access.

The primary goal of electricity labeling, or disclosure, is to provide consumers information about price, environmental characteristics, and other attributes of their power.

Chapter four of this report summarizes and discusses the Cost Studies done by the electric utilities. Subsections 2(1) (a) and (b), (2), and (3) of the bill require:

Sec. 2. (1)(a) By September 30, 1998, each electrical company shall submit a cost study described in subsections (2) and (3) of this section,

** * **

(b) Except as provided in section 4 of this act, by September 1, 1998, each consumer-owned utility shall submit a cost study described in subsections (2) and (3) of this section,

** * **

(2) Except as provided in section 4 of this act, by September 30, 1998, every electric utility shall unbundle. At a minimum, an electric utility shall include in such unbundling the accounting treatment for generation and energy supply, delivery services separately identifying transmission, distribution, and control area services, metering and billing, customer account services, programs to support conservation or renewable resources other than hydroelectric power, fish and wildlife mitigation, general administration and overhead, and taxes; the functionalization of costs separately for generation and energy supply, transmission, distribution, and other; the classification of costs separately to include, but not be limited to, energy and capacity; and the assignment or allocation of costs separately to include, but not be limited to, residential, small commercial, industrial, and other. For the purpose of chapter . . . , Laws of 1998 (this act), as directed by the commission for an electrical company or the governing body of a consumer-owned utility, the electric utility shall use the data from either the cost study used to formulate the retail rates in effect as of the effective date of this act, or a more recent cost study.

(3) The cost study required of each electric utility under subsection (1) of this section shall include the following documentation:

(a) A description of the fundamental cost study theory used, such as fully embedded costs, marginal or incremental costs, or some combination thereof;

(b) A detailed description of the classifications, functions, and assignments or allocations of electrical service unbundled;

(c) The costs attributed to each of these classifications, functions, and assignments or allocations and, if proportional attribution of costs between classifications, functions, and assignments or allocations is necessary, the proposed method of attribution;

This chapter of the report includes a brief description of what a cost study is, summarizes the data reported, provides several analyses of the data and discusses data consistency issues. The data provided show a snapshot of the costs recovered in current bundled rates; they do not show what stand-alone costs are for unbundled services. Nor do they constitute a basis for setting new rates or levels of approved revenue.

Chapter 1.0 SERVICE QUALITY REPORTING

The legislation requires the Commission and the Auditor to report jointly on the results of service quality reports submitted by selected utilities within the state. The legislation directs that the report include a summary of the service quality reports, and observations about the consistency or lack of consistency among utilities in the amount and kinds of information available regarding service quality. Further, the legislation asks the Commission to describe any issues arising from the service quality reports.

2831 required the electric utilities to submit data, to the extent they are currently collected and reasonably available, about the level of satisfaction of the utility's customers as measured by customer surveys, and the number of consumer complaints filed during a calendar year with the utility's governing body. 2831 also required utilities to provide a copy of the survey instrument or script used to collect the survey information, if available. To seek comparable information, the Commission and the Auditor provided written guidelines to the utilities describing data the utilities could submit to meet the requirements of 2831.

Twelve utilities submitted service quality reports; not all utilities could provide information in all areas. Reporting utilities included three electric companies and nine consumer-owned utilities.

1.1 CUSTOMER COMPLAINT INFORMATION

Table 1.1 Customer Complaints Filed in Calendar year 1997
Type of Complaint:

Utility	Billing	Service	Tariff	Misc.	Total	Complaints per 1,000 customers
Puget Sound Energy	252	81	15	56	404	.47
PacifiCorp	35	5	0	4	44	.39
Washington Water Power	139	2	1	5	147	.75
Snohomish County PUD	n/a	n/a	n/a	n/a	54	.22
Clark Public Utilities*	n/a	n/a	n/a	n/a	n/a	n/a
Benton County PUD**	n/a	n/a	n/a	n/a	n/a	n/a
Tacoma Power**	n/a	n/a	n/a	n/a	n/a	n/a
Grant County PUD**	n/a	n/a	n/a	n/a	n/a	n/a
Cowlitz County PUD**	n/a	n/a	n/a	n/a	n/a	n/a
Chelan County PUD**	n/a	n/a	n/a	n/a	n/a	n/a
Seattle City Light**	n/a	n/a	n/a	n/a	n/a	n/a
Grays Harbor Co. PUD	n/a	n/a	n/a	n/a	n/a	n/a

n/a – data not collected or reasonably available.

* Clark Public Utilities customers not satisfied with the results of a complaint may appeal to a hearings officer.

In 1997, Clark Public Utilities received 11 requests for hearings.

**These utilities do not track this information.

2831 required consumer-owned utilities to report the number of complaints filed with the utility's governing body. For consumer-owned utilities, this is either a district's board of commissioners or city government. Electric companies are required to report the number of complaints filed with the Commission.

Of the twelve utilities reporting, only four could supply statistics on the number of complaints filed: the three electric companies and the Snohomish County Public Utility District (PUD). Snohomish reported the total number filed with its governing body, while the electric companies reported the number filed by category. **Table 1.1** illustrates the complaints reported.

1.2 CUSTOMER SATISFACTION

The form and substance of information provided to the Commission and the Auditor regarding customer satisfaction surveys varied among utilities. Again, it is important to emphasize that 2831 did not require new surveys to be conducted. It only required utilities to report information that was currently collected and reasonably available. Puget Sound Energy and Washington Water Power² both submitted selected questions and answers from broadly focused customer surveys conducted for purposes not directly related to the reporting requirement in 2831. Snohomish County PUD, Clark County PUD, Grant County PUD and Seattle City Light submitted entire survey instruments recently undertaken, as well as the full results of these surveys. PacifiCorp, Grays Harbor County PUD and Benton County PUD provided a summary of surveys previously completed and a summary of the results of those surveys. Tacoma Power and Chelan County PUD provided a copy of the survey instrument with a summary of the results. Cowlitz County PUD does not conduct formal customer surveys.

All surveys were conducted by telephone through a third party independent research firm. The questions asked in the surveys varied widely among utilities. However, there were a number of survey questions common to several utilities. For example, eight utilities asked about overall satisfaction with the utility.

Five utilities asked the following questions:

- Does the customer believe the utility's bills are readable/easy to understand?
- Does the customer believe the utility restores power timely after an outage?
- Did the telephone representative satisfy the customer's needs?
- What was the customer's overall satisfaction with their customer service experience?

Four utilities asked if the customer believes the utility provides reliable service.

Three utilities asked questions about whether utility staff seemed knowledgeable; whether the customer was treated well or courteously; whether billing was accurate; and whether the customer was satisfied with overall call center experience.

Two utilities asked whether the customer received a quick, accurate response to their question; whether field work was prompt; whether estimated restoration time after an outage was accurate; whether the customer was satisfied with the payment options available; whether it was easy to reach appropriate staff at the utility; how the automated phone system worked; whether they were connected to the appropriate person quickly; whether the request was handled quickly; and whether staff was flexible in handling the inquiry.

Additionally, individual utilities asked questions such as the usefulness of past electricity use comparisons on the bill or bill inserts, honest or ethical treatment by the utility, specific issues regarding experience with field staff, meeting customer expectations, the outage reporting system, and overall billing and credit issues.

While some consistency existed among utilities concerning the subject matter of survey questions, the results of the surveys are difficult to compare because of differing methods used to record responses. Two utilities asked customers to rate their services on a scale of 1 to 10; two others used a scale of 1 to 7. Four utilities used some form of rating such as “poor, fair, good or excellent.” One used a “yes/no” format and still others structured each question with a different response scale.

Table 1.2 Responses to Survey Questions: Rank Overall Satisfaction with Utility

Utility	Approval Rating	Rating Scale
Puget Sound Energy	92.7%	Respondents answering 5 - 7 on a scale of 1 - 7
Washington Water Power	91%	Respondents answering “good” or “excellent”
Snohomish County PUD	88%	Respondents answering “good” or “excellent”
Clark Public Utilities	96%	Respondents answering “pretty good” or “excellent”
Benton County PUD	79%	Respondents answering 6 - 7 on a scale of 1 - 7
Chelan County PUD	88.4%	This rating was provided without a description of the scale
Grays Harbor Co. PUD	72%	Respondents answering 6 - 7 on a scale of 1 - 7
Seattle City Light	86%	Respondents answering “good” or “excellent”

The differences among the survey questions and the different scales used to score responses, even when questions were similar, mean that analysis, and even summary, of results is for most questions not possible. However, for the question most commonly asked, summarization is possible and useful. Eight utilities asked about the customer's overall satisfaction with the utility.

Table 1.2 summarizes the responses to that question. These data indicate that, where measurement information exists, customer satisfaction with the utility and its service is relatively high, ranging from 72 to 96 percent.

1.3 ISSUES RAISED BY CONSUMER COMPLAINT AND SATISFACTION DATA REPORTED FOR 2831

Based on the information reported, we have not identified any important issues or problems regarding the level of customer complaints or satisfaction with utility service. However, there are important issues to note regarding the availability of consumer attitude information.

First, not all utilities collect and/or maintain the information asked for in 2831. All three electric companies could report the number of complaints filed with the Commission. Only one consumer-owned utility, however, could report how many complaints were filed with its governing body. The other consumer-owned utilities did not track the number of complaints filed. This may be information important for the electric utilities and policy makers to have if measuring the level of customer satisfaction with service is either a state or local objective.

Second, not all of the information that may be necessary in considering customer satisfaction is readily available from both electric companies and consumer owned utilities. For electric companies, the state public records act provides for protection of confidential information. See, RCW 42.17.310 (q) and RCW 80.04.095. An electric company can file information with the Commission that the company considers confidential, and the Commission will not release that information if the company is willing to go to court to protect it. This posed potential problems in gathering information about customer satisfaction surveys. Initially, all three electric companies filed all of their survey information as confidential. They were reluctant to share publicly much of the information, which they considered proprietary. The Commission staff worked with the companies to negotiate the release of some limited information that would be used to satisfy the requirements of 2831, and to gain a release to allow an employee of the Auditor to review the remaining confidential information in the possession of the Commission.

The statutes providing for exemption from public records disclosure do not apply to consumer-owned utilities. All of the information submitted by the consumer-owned utilities regarding customer satisfaction surveys is considered public record, and agency staff could use that information as soon as it was received, without limitations. This caused a disparity between the electric companies and the consumer-owned utilities in the amount and type of information available regarding consumer satisfaction.

Third, all of the information received from both electric companies and consumer-owned utilities was gathered by the utilities themselves. In many cases, the utilities gathered information specific to issues in their service territory, for purposes other than to satisfy 2831 or to simply measure customer satisfaction. For example, some utilities asked questions dealing with marketing concerns rather than with customer satisfaction. In the portions of surveys addressing consumer satisfaction, the utilities used different wording, and different scales to measure results. If it is important to the State's interest to measure the level of satisfaction of electricity consumers statewide, reliance on sources other than utility surveys may be more practical. For example, standardized surveys could be periodically administered, either by the utilities or by some other entity. This would not preclude individual utilities from asking specific questions as a part of the standardized survey, but would ensure that all electricity consumers have the opportunity to respond to the same set of questions common to all the surveys.

Chapter 2.0 ELECTRICITY SERVICE RELIABILITY STATISTICS

As part of their service quality and reliability reports, the legislation, in Subsections 2(4)(c) and (d) directed the electric utilities to submit reliability performance data consisting of the number of minutes the average customer or feeder line is without electricity during a calendar year; and the number of times the average customer or feeder line is without power during a calendar year.

Subsection 3(2)(c) of 2831 also directs the agencies to include in their legislative report a summary of the reliability reports submitted by electric utilities; observations regarding the consistency or lack of consistency among utilities in the amount and kinds of information available regarding reliability; and descriptions of any issues arising from the reliability reports.

2.1 SERVICE RELIABILITY DATA REPORTED BY THE ELECTRIC UTILITIES

Each utility reported information collected and reasonably available regarding the number of minutes and times the average customer was without electricity.³ The data reported are listed in **Table 2.1**.

Table 2.1 Minutes and Times of Average Customer Interruption in 1997

Utility	SAIDI (minutes)	SAIFI (times)
Washington State Average ^a	92.38	1.04
Benton County PUD	Not Available	Not Available
Chelan County PUD	42.84	0.21
Clark County PUD	52.00	2.00
Cowlitz County PUD ^b	216.00	1.20
Grant County PUD #2	63.70	0.83
Grays Harbor County PUD	268.40	2.33
PacifiCorp	68.28	0.93
Puget Sound Energy	104.65	1.04
Seattle City Light	72.68	1.24
Snohomish County PUD No. 1	50.50	0.73
Tacoma Power ^c	57.60	1.22
Washington Water Power ^d	80.78	8.30

- (a) State average calculated as weighted average using customer data available from other sources. State average does not include data from Clark County PUD and Washington Water Power because both utilities reported momentary interruptions; all the other utilities reported only sustained interruptions. State average also does not include data from Tacoma Power, which reported CAIDI instead of SAIDI (see table-note c).
- (b) Data from this utility is for the period September 1, 1996 through August 31, 1997.
- (c) This utility reported CAIFI not SAIDI. CAIFI calculates the duration of outages for customers who actually had outages. It is not a full system customer average.
- (d) Numbers are for 1993. This utility does not have more recent data.

Based on this information, in 1997 the average customer in Washington experienced 1.04 service interruptions. The average total period of interruption was one hour and 38 minutes. The lowest reported average number of sustained interruptions was 0.21; the highest was 2.33.⁴ The shortest reported average minutes of interruption was 43; the longest, four hours and 28 minutes.

The data presented in **Table 2.1** show that variation among utilities falls within a relatively narrow range, especially for the frequency of interruption (i.e. number of times the average customer experiences an interruption). Excluding the lowest and highest data points shows that most customers experienced between one and two outages regardless of the utility. The length of outages varies more by utility. The three longest average minutes of outage were reported by utilities west of the Cascades. This likely represents the greater incidence of storms and related damage from trees often experienced west of the mountains.

2.2DISCUSSION OF THE DATA AND CONSISTENCY ISSUES

The electric utility industry generally recognizes two indices that measure the minutes and times of power outages for the average customer. The System Average Interruption *Duration* Index (SAIDI) measures minutes of interruption; the System Average Interruption *Frequency* Index (SAIFI) measures times of interruption. With one exception all utilities reported SAIDI and SAIFI for their systems.

Unfortunately, no industry standard exists for calculating SAIDI and SAIFI. The Institute of Electrical and Electronic Engineers (IEEE) will likely adopt a proposed standard before the end of 1998. Meanwhile, differences both in how utilities collect data and what they include in SAIDI and SAIFI mean the numbers generally are not comparable. Rather, the data are primarily useful to provide a sense of the average performance of distribution systems in the state.

The following is a list of issues that may affect the consistency and comparability of the SAIDI and SAIFI data.

- The reported SAIDI and SAIFI may include outages of differing minimum durations.

The proposed IEEE standard recommends utilities report only “sustained outages,” which are those lasting five minutes and longer. In the reliability reports submitted to the agencies, some utilities reported outages consistent with this standard. Other utilities reported outages lasting one minute and longer. Two utilities included “momentaries” in their calculations, which are outages lasting less than one minute. Including momentaries can greatly increase SAIFI, because there may be many very short interruptions lasting only a second or two, especially in areas that experience frequent lightning storms. Many momentary interruptions usually do not add up to a long duration of interruptions. Therefore SAIDI is not greatly affected.

- SAIDI and SAIFI may or may not include outages caused by storms. Also, utilities use different definitions for storms.

Generally, gathering data during storms is not a high priority for utilities. It takes a back seat to service restoration. Therefore storm-based data are generally not as accurate as data gathered during periods of normal operations. Including storm-caused data in SAIDI and SAIFI diminishes the accuracy of the measures. It can also greatly increase SAIDI and SAIFI. Utilities in Washington have reported storm-caused interruptions that represent from 13 to 41 percent of total system SAIFI, and from 30 to 62 percent of total system SAIDI⁵. Knowing that utilities have excluded storm-caused outages from their data does not necessarily mean the data is more comparable because utilities often use different definitions for storms.

- SAIDI and SAIFI may or may not include interruptions from all causes, i.e. generation, transmission and distribution system events.

A utility may choose not to track outages that are caused by events not on its own system. These would usually be events at generation or transmission facilities owned by a different company. Excluding such events provides a better picture of the utility's own performance, but it reduces SAIDI and SAIFI actually experienced by customers.

SAIDI and SAIFI may or may not include partial feeder outages. If an entire feeder line is disrupted, a utility often knows how many customers are affected and for how long. If only part of a feeder loses power, the utility must estimate the impact. A utility may exclude partial feeder outages from its calculations if it does not have an effective way to make such estimates. Not counting partial feeder outages can result in a low SAIDI and SAIFI.

- SAIDI and SAIFI may or may not include aspects of phased restoration of service.

Power interruptions are often restored in incremental steps. For example, customers who have lost power may be temporarily restored by switching them to another circuit while a damaged line is repaired. Some utilities attempt to track these steps and include the data in their calculations. The more capable the tracking, the more accurate the SAIDI and SAIFI. Other utilities begin the duration count with the first phone call and end the count when the last customer is restored, despite who may have been restored along the way. Not starting the count until the first phone call generally leads to a small underestimate of duration. Not ending the count until the last customer is restored can lead to a significant overestimate of duration.

- SAIDI and SAIFI may be based on very different methods of estimating the number of customers affected.

All utilities have some basis for counting customers without power. Few utilities know exactly how many customers are on a given line, especially for small sub-circuits of their systems. However, some utilities have quite sophisticated tracking systems that link

frequently updated customer information with equipment outage information. Other utilities use in-field personnel to estimate the number of customers affected. Both SAIDI and SAIFI are significantly affected, either upward or downward, by the accuracy of customer counts.

- SAIDI and SAIFI may or may not reflect data acquisition and management changes.

Most utilities attempt to improve their data management capabilities on an ongoing basis. This has been especially true over the last decade, as computer and digital communications technologies have improved greatly and as prices have lowered. These technologies allow utilities to improve the accuracy of their outage tracking and calculate more accurate SAIDIs and SAIFIs. This has a number of consequences for tracking trends in these statistics. Utilities in Washington and nationwide have reported that their SAIDIs and SAIFIs have increased, suggesting worse reliability, even as their reliability improves. These trends are likely the result of better tracking, not deteriorating reliability. Changes in data acquisition and management can make it difficult to track trends both among utilities and for an individual utility. While this study did not require a trend analysis, these complications for interpreting trends mean that using the current data as a baseline to judge future performance may not be justified.

2.3SUMMARY

Even most standard engineering performance measures have significant limitations. Unfortunately, these weaknesses limit their value for purposes in which we have the most interest: providing consistent measures of current levels of reliability, tracing trends over time and comparing one utility (or group of utilities) to another. Nevertheless, these are the best reliability performance indices available. As long as we keep these limitations in mind, they allow for some observations about performance reliability in Washington. Issues surrounding reliability performance data and the factors and trends affecting electricity service reliability are discussed in more detail in a separate report to the legislature due to be delivered January 1, 1998.⁶

Chapter 3.0 INFORMATION DISCLOSURE

3.1 INTRODUCTION

2831, Section 3(1)(e) requires the agencies to include in their report:

An examination of alternative formats for simple, standardized disclosure of fuel mix, air emission, and other environmental impacts of coal, hydroelectric, natural gas, nuclear, wind, and other generating resources, including the approaches used by utilities that have offered pilot programs to their customers allowing market access.

The primary goal of electricity labeling, or disclosure, is to provide consumers with information about price, environmental characteristics, and other attributes of their power. Labels are essential to consumers faced with electricity choices, as they allow those consumers the ability to compare available products and to make informed choices. With the choices they make, those consumers can influence the price of their electricity as well as the type of generation used to produce it. Even in states not engaged in electricity competition, labels can inform and educate retail customers about the characteristics of their power. Labels can prepare those customers for possible choices they may be faced with in the future.

This portion of the report provides discussion and examples of labeling formats for various characteristics of electricity, including fuel mix, environmental effects of generation, and price. In addition, a summary of the Western Tracking and Disclosure Project, an effort by western states to achieve uniform tracking of electricity in our region, is provided. Accurate tracking of electricity is necessary to ensure credible electricity information is provided to consumers.

3.2 BACKGROUND

Several states in the U.S. offer or have plans to offer consumers of electricity choices in the products they buy. As this new more competitive electric industry emerges, more focus is placed on the importance of providing consumers information to enable them to make informed choices. The changing electricity environment has sparked interest in educating consumers, even in those states that have chosen not to restructure retail electricity markets. In the West, at least three states, California, Arizona, and Montana have adopted or have plans to adopt disclosure criteria.

In November 1996, the National Association of Regulatory Utility Commissioners (NARUC) adopted a resolution calling for enforceable, uniform standards that would allow retail consumers to easily compare price, resource mix, and the environmental characteristics of their electricity purchases. In an attempt to aid in the implementation of this resolution, NARUC formed the National Council on Competition and the Electric Industry (NCCEI) and initiated a Consumer Information Disclosure Project to assist state regulators and legislators to address consumer information needs in a competitive electricity environment.

NCCEI's project includes considerable research published in various studies designed to assess customer understanding of disclosure and the determination of effective label formats. In addition, disclosure components of pilot projects conducted by utilities in Washington and elsewhere in the Northwest provide valuable information on labeling. In May 1998, PacifiCorp offered residential customers in Klamath County, Oregon, the opportunity to choose from a variety of electricity options, including market-based pricing, renewable (wind and geothermal) energy, and an option allowing an additional fixed contribution to limited-income residents of Klamath County. Customers eligible to participate in the pilot were mailed a disclosure label that included information about each choice's features, fuel source, environmental effects, and price. A second enrollment period is planned for late-fall 1998, during which participants may change options or additional eligible customers may choose to commence participation in the pilot. PacifiCorp revised its disclosure label for the second sign-up period, based on feedback from customers and other interested parties.

In its second residential and small commercial retail electric pilot initiated in June 1998, the More Options for Power Service II (MOPS II) pilot, the Washington Water Power Company offered eligible customers in Deer Park, Washington and Hayden and Hayden Lake, Idaho the opportunity to choose from a menu of electricity choices similar to PacifiCorp's pilot, including market-based rates and renewable resource options. As part of its pilot information material, the Washington Water Power Company sent eligible customers a disclosure label identifying the fuel mix and air emissions associated with each option, as well as a typical bill comparison. Following the first two months of enrollment in the MOPS II pilot, the Washington Water Power Company conducted focus groups to assess consumer understanding of the pilot information and electricity disclosure label mailed to inform its eligible customers about their electricity choices.

Puget Sound Energy developed a label for its retail access pilot that was originally scheduled to commence in early 1998; however, a lack of supplier interest has precluded the pilot from being implemented for residential and small commercial customers.

The labeling examples provided in this report draw primarily from research published by the NCCEI and from the retail pilot programs of PacifiCorp, the Washington Water Power Company and Puget Sound Energy. Attachment A contains the electricity label of PacifiCorp's second enrollment period for the Klamath County pilot project. Attachment B contains the disclosure component of the Washington Water Power Company's MOPS II pilot information brochure. Attachment C is a copy of the label PSE designed for its residential and commercial retail access pilot. Attachment D contains a copy of the recommended electricity label based upon NCCEI's Mall Intercept Study (Kenneth Winneg *et al*, "Label Testing: Results of Mall Intercept Study," The National Council on Competition and the Electric Industry, April 1998). The study was specifically designed to help determine which label formats are most effective at conveying information to consumers. The research evaluated consumers' ability to understand information and perform various tasks related to comparing electricity products.

3.3 LABEL FORMATS

3.3.1 FUEL MIX DISCLOSURE

Disclosure of fuel mix information reveals to consumers primary energy sources used to generate the electricity they purchase. Design of the fuel mix information requires the determination of fuel categories to be reported and the designation of a format to be used. Developing a list of fuel mix categories is largely subjective, and may differ depending upon customer preferences in various regions. In the Northwest, the following broad categories are relevant: hydroelectric, coal, oil, natural gas, nuclear, biomass, and renewable energy. Biomass and renewable energy may be combined in a single category, or broken down further into specific fuels, such as wood waste, wind or solar. Power from unknown sources, such as power from short-term contracts or spot market purchases, may be incorporated in the fuel mix information as a system average mix (such as the mix for the U.S. portion of the Northwest Power Pool).

Fuel mix can be presented in tabular formats or graphical representations, such as pie charts. One NCEEI study, the New England Information Disclosure Project (Tom Austin *et al*, "Uniform Consumer Disclosure Standards for New England: Report and Recommendations to the New England Utility Regulatory Commissions," The National Council on Competition and the Electric Industry, October 1997) suggested that historical research on fuel mix disclosure indicates a slight preference for the pie chart format. A shortcoming of that format, however, is that supply sources with zero contribution are simply absent from the chart. In its Mall Intercept Study conducted later, NCEEI found that simple tabular formats generally allow respondents to have the most accurate understanding of fuel mix information. One experiment in that study showed that including average or regional "system mix" alongside a product's fuel mix caused substantial confusion among respondents challenged with the task of accurately understanding fuel mix information.

In its Klamath County pilot, PacifiCorp originally disclosed fuel mix information in pie charts; however, it revised the information into tabular formats for the second version of its label (Data Appendix 3.0, Attachment A), based on feedback from customers. PacifiCorp designated five categories for its fuel mix: hydro, coal, gas/oil, nuclear, and other. Renewable resources (geothermal and wind) are contained in the "other" category.

Both the Washington Water Power Company and Puget Sound Energy chose to display system fuel mix in pie chart formats in their pilot labels, as seen in Attachment B and Attachment C. In its MOPS II pilot label, the Washington Water Power Company includes wind power and power generated from wood waste (biomass) as individual categories, since these sources are designated as options for eligible customers. The Washington Water Power Company's label also includes a system average fuel mix for comparison to the resource mixes of the various pilot options. System average fuel mix is calculated as the U.S. portion of the Northwest Power Pool mix, and is based on data submitted to the Western System Coordination Council (WSCC) by utilities and generators for the 1997 forecast year.

NCCEI's recommended fuel mix format is shown in its label in Attachment D. The tabular format is similar to PacifiCorp's label, with the addition of a "total" category, which sums the fuel category percentages.

3.3.2 DISCLOSURE OF ENVIRONMENTAL EFFECTS OF GENERATION

3.3.2.1 Air Emissions

Emissions disclosure reveals information about environmental impacts of specific electricity generation sources and provides a way to highlight differences between generators using a particular fuel type. Disclosure of emissions information is typically reported where reliable data is available for pollutants emitted in significant amounts causing environmental or public health hazards. Typically, those pollutants include sulfur dioxide (SO₂), produced when fuels containing sulfur (primarily coal and oil) are burned, nitrogen oxides (NO_x), produced in any combustion process, such as when fossil fuels and biomass are burned, and carbon dioxide (CO₂), produced when carbon-based fossil fuels are burned. The emissions of these pollutants can be reported as a unit production rate, such as grams or milligrams per kilowatt-hour (kWh), for each. As with fuel mix data, effective presentations include graphical representation, such as bar charts, or tabular formats, and may include a comparison of the data to a regional average. In its Mall Intercept Study, NCCEI found that comparing emissions data to a regional average was a more effective approach to disclosing this information than exclusively reporting raw emission data.

In its Klamath County pilot label (Attachment A) PacifiCorp provides air emissions information in vertical bar chart format for each pollutant in milligrams per kWh, relative to a horizontal line representing the regional average. In addition, PacifiCorp provides text that describes the main environmental effects of various power sources common to the Pacific Northwest.

Both the Washington Water Power Company (Attachment B) and Puget Sound Energy (Attachment C) use horizontal bar charts to disclose air emissions data in their pilot labels, similar to the format recommended by NCCEI (Attachment D). The Washington Water Power Company's regional comparison takes place in an independent chart, while Puget Sound Energy's regional comparison is incorporated into the air emission chart of each product. Puget Sound Energy includes a description of air emission sources below its bar chart.

3.3.2.2 Nuclear

Spent nuclear fuel is a radioactive solid waste created in the generation of nuclear power. Spent fuel is accumulated by operators of the nation's nuclear facilities and is currently stored in temporary sites. At this time, no safe permanent site has been designated for its disposal.

Spent fuel can be reported in a manner similar to air emissions, as production of heavy metal solid waste in micrograms per kilowatt hour ($\mu\text{g/kWh}$). Illustration can take the form of graphical representation, such as a bar chart, or a table.

The Washington Water Power Company does not offer eligible customers in its MOPS II pilot electricity options including nuclear power; therefore, its pilot label does not address environmental impacts of nuclear generation. Puget Sound Energy does not require potential energy suppliers in its retail access pilot to disclose spent nuclear fuel accumulations.

PacifiCorp's Klamath County pilot label (Attachment A) includes a vertical bar chart disclosing spent nuclear fuel accrual relative to a regional average, identical in presentation to the air emissions format.

3.3.2.3 Hydroelectric

The environmental impacts of hydroelectric generation are perhaps the most challenging attributes to report on a label, because of the difficulty in quantifying those impacts. There are several ways to educate consumers about the impacts of hydropower. The simplest method is to include a statement informing consumers that potential risks to the environment exist when electricity is generated from hydroelectric dams. In its disclosure label, California makes a size distinction for hydropower based on PURPA's Qualifying Facility definition. Hydro facilities less than 30 MW are considered renewable. Making such a distinction, however, is arbitrary, and does not directly address environmental impacts.

American Rivers, a national conservation organization whose mission is to protect and restore river systems in the U.S., together with Green Mountain Energy Resources, (Green Mountain), a Vermont-based utility, has developed a system to identify hydropower plants with low environmental impacts. In September 1998, American Rivers and Green Mountain published draft Low-Impact Hydropower criteria that identify the following six key areas for review: fish, river flows, water quality, land protection, cultural resource protection, and recreation. American Rivers envisions that hydropower facilities will complete questionnaires concerning their dams, and those facilities successfully meeting all six criteria will obtain low-impact designation in the form of certification. The process for certifying hydro facilities and for administering the certification system is still under development. A copy of the draft Low-Impact Hydropower Criteria can be found in Attachment E.

PacifiCorp attempts to address environmental impacts of hydroelectric generation on its pilot label by disclosing the percentage of the power supply of each option not known to meet the latest hydropower licensing standards for fish and wildlife impacts set forth in the Electric Consumers Protection Act of 1986 (ECPA). Hydro facilities licensed after ECPA was implemented are considered to meet the licensing standards, and those licensed before implementation of ECPA are considered "not known" to meet those standards. Similar to California's hydro distinction based on size, the method does not address environmental impacts of hydroelectric generation. Neither the Washington Water Power Company nor Puget Sound Energy attempts to disclose impacts of hydropower.

3.3.3 PRICE DISCLOSURE

In its research, NCCEI found that disclosure of price information is the primary concern of customers faced with decisions regarding their electricity products. (Alan S. Levy *et al*, “Information Disclosure for Electricity Sales: Consumer Preferences from Focus Groups,” The National Council on Competition and the Electric Industry, July 1997). In its pilot evaluation focus groups, the Washington Water Power Company learned that price was the most important factor affecting customers’ electricity choices. Despite the fact that price was most important, NCCEI research showed that consumers had difficulty in comparing price offers, even when the price structures differed in very minor ways.

There are two primary ways to disclose price information. First, price can be reported on a per kWh basis. Where choice is involved, it is common to report only the energy, or generation, portion of the cost, excluding or listing separately the delivery component of the cost. For energy products with tiered rates, that is, rates that change with increased usage, average generation price for varying levels of usage may be displayed. The second way to report price information is through a “typical bill” comparison. For residential customers, for example, a comparison of cost for the average customer at a given kWh usage level for each product allows customers to compare across products without additional calculations.

In its original Klamath County pilot, PacifiCorp’s label (Attachment A) displays the price per kWh of each option, along with detailed information describing the basic charge and the delivery charge in a footnote. Based on feedback from customers, PacifiCorp added a “sample bill” comparison to its revised label to be mailed to customers for the second enrollment period. A sample bill for two different energy usages is shown for each customer class for each pilot option.

The Washington Water Power Company’s pilot label (Attachment B) discloses the residential average bill based on average monthly consumption of 1000 kWh for each of the pilot options. In addition, the label shows the average total price per kWh of each option including delivery charges, and the difference between the Washington Water Power Company’s traditional or existing tariff price per kWh and the option price.

Puget Sound Energy’s pilot label (Attachment C) discloses varying levels of usage based on average monthly use, and the corresponding cost per kWh. In its recommended label, NCCEI displays varying levels of use and the average monthly generation bill, excluding delivery charges and other fixed charges (Attachment D).

3.3.4 OVERALL LABEL PRESENTATION

Research and the experience of utilities who have tested label formats on consumers suggest that disclosure information should be simple, and should be presented in a clear and uniform manner. NCCEI expressed the need for simple labels in all of its disclosure research.

Study research showed that consumer understanding of disclosure information and consumers' ability to use the information to make informed choices was substantially improved when all products were labeled in a uniform fashion.

In its focus groups, the Washington Water Power Company found that although customers could derive the information needed to make choices in their electricity service from the pilot label, most customers were overwhelmed and discouraged by the complexity of the label itself. Customers suggested that the label could be improved by simplifying the format, and by removing the technical discussions regarding the calculation of market prices and the detailed price comparison information. Customers thought that more technical or detailed information should be available upon request to those customers who specifically request it once a simple label has been distributed.

PacifiCorp, too, found in its pilot that simplicity is an important feature of disclosure. In the disclosure material PacifiCorp designed for its second pilot enrollment following feedback from customers, the label is separated into two separate fold-outs. The first label contains a description of the features, price per kWh and fuel source information for each option. PacifiCorp considers the information in that fold-out to be essential information customers need to make choices. The second label contains information PacifiCorp considers somewhat less essential, such as the more detailed price information and information describing the environmental effects of generation.

3.4 VERIFICATION OF DISCLOSURE INFORMATION

Providing accurate and credible information to consumers about their electricity requires some way of verifying that information and ensuring that the electricity itself is not sold more than once to those consumers. By tracking electricity sales to consumers, the characteristics of electricity products sold can be verified. The electricity grid consists of a distributed set of generators feeding power into a common network that is drawn on by a community of consumers. Physically, one cannot identify or track specific additions to or withdrawals from the grid. Thus, there exists a disconnection between the physical production of energy and the contracts used to sell it as a product.

Beginning in June 1998, a steering committee and working group comprised of members of the Public Utilities Commissions and Energy Offices of Western states initiated a project whose first priority was to develop a consensus approach to achieve uniform tracking of electricity in the Western electricity grid. Following several stakeholder meetings and working group discussions, participants in the project reached consensus on an approach to track and document characteristics of electricity sold across state boundaries. The approach is founded on certificate-based tracking. Certificates would be issued to generators as electricity is produced. Those certificates represent the "attributes" of the electricity produced, and may be traded in a secondary market. An end use seller of electricity would be required to possess certificates to make specific claims about the electricity it sells. In this way, dollars flow directly to the generators whose product comes from desirable sources of electricity. The Western consensus approach to

tracking, developed as a result of the project, can be initiated through participation by states and provinces in the Western grid with an immediate need, and can be expanded to the rest of the region over time. A summary of the consensus is provided in Attachment F.

The tracking approach will be launched initially as a one-year pilot project in 1999. The pilot was presented and endorsed by members of the Committee on Regional Electric Power Cooperation (CREPC) at a meeting in San Diego in October 1998. CREPC, an organization of Public Utility Commissions and Energy Offices from the states and provinces of the western electric grid, or interconnection, was established in the mid-1980s to coordinate the policies of the those members, as they relate to the issues involving the electric grid.

The consensus approach is derived from California's existing model and allows for the introduction of tradable certificates. Currently in California, system operators are required to report hourly generation data, by generator, by kWh, including fuel type quarterly to the California Energy Commission (CEC). Retail sellers of electricity who make specific product claims to their customers are required to provide an audited report to the CEC backing up the claims and verifying that the power was not sold more than once. The CEC verifies that claims are accurate, and calculates a California residual "net system power mix" comprised of all electricity generation plus net purchases less claimed power. In the Western tracking approach, certificates could replace audits for claims made on electricity products.

A critical element of the western consensus tracking approach is the development of a region-wide clearinghouse, whose role would be to issue certificates to generators, and to calculate a residual regional power mix or mixes. The sum of all claims plus residual mixes must equal total generation in the Western Interconnection. During the one-year pilot, the clearinghouse will reside within the CEC. States collecting data on retail claims will send the data to the CEC. The CEC will compare each generator's claims with its annual generation to ensure power is being sold only once.

States and provinces participating in the tracking pilot are expected to sign a Memorandum of Understanding (MOU) outlining the objectives and strategy of the pilot. Four states are currently considering state-level customer disclosure initiatives--California, Arizona, Montana, and Nevada--and would be the most likely to participate in the pilot. A draft copy of the MOU is contained in Attachment G.

In addition to the tracking mechanism, the Western Tracking and Disclosure Project sought to develop model rules that may be adopted by states wishing to allow disclosure of electricity information to consumers. The model rules are still under development, and are expected to be finalized by the end of the year. A very early draft copy of the rules is provided in Attachment H.

3.5 SUMMARY

The agencies were directed by the legislature to report on alternate formats for disclosure of electricity attributes. Based on research conducted by the National Council on Competition and the Electric Industry and on electricity retail choice pilots conducted in the Northwest, the following conclusions can be drawn:

- Disclosure information should be simple, and should be presented in a clear and uniform manner.
- Research shows that fuel mix information is most successfully disclosed in a simple tabular format. Fuel mix disclosure may include the following broad categories: hydroelectric, coal, oil, natural gas, nuclear, biomass and renewable energy. Categories may be broken out further or consolidated as appropriate.
- Disclosure of air emissions (CO₂, SO₂, and NO_x) and of spent nuclear fuel creation is best presented in a bar chart format. Research indicates that comparing emissions data to a regional average is the most effective approach.
- Disclosure of environmental effects of hydroelectric generation is challenging, because of the difficulty in quantifying the impacts. American Rivers and Green Mountain Energy have published draft Low-Impact Hydropower criteria to review the following aspects of hydroelectric dams: fish, river flows, water quality, land protection, cultural resource protection, and recreation. American Rivers is working on a process to certify hydro facilities meeting these criteria with low-impact designation.
- Research indicates that price disclosure is the primary concern of customers faced with making electricity choices. Price information can be displayed on a per kWh basis, or through a “typical bill” comparison. Research was mixed regarding the best format to disclose price information.
- A Western Tracking and Disclosure Project is underway, and has developed an approach through consensus among Western states to achieve uniform tracking of electricity in the Western grid. The tracking approach will be implemented as a pilot in 1999. The California Energy Commission will act as a regional clearinghouse to issue “certificates” to participating generators. Participating retail sellers will need to possess certificates to make claims about their electricity products. Participating retail sellers not making claims will disclose a “regional residual mix”, calculated by the California Energy Commission.

3.6 CHAPTER 3.0 APPENDIX

The following documents are included in the Appendix to this chapter.

Table of Contents

Attachment A “Your values Your power” and “Klamath County Customer Choice Program, More Details”

These two brochures are the electricity disclosure labels of PacifiCorp's second retail access pilot project in Klamath County, Oregon.

Attachment B “Washington Electric Prices”

This brochure is the Washington Water Power Company's electricity disclosure label included in the information material mailed to customers eligible to participate in the Washington Water Power Company's second retail access pilot in Deer Park, Washington and Hayden and Hayden Lake, Idaho.

Attachment C “Energy Supplier or Your Energy Product”

This label was developed for Puget Sound Energy's retail access pilot which was not implemented because of lack of supplier interest.

Attachment D “Electricity Facts”

This electricity disclosure label is recommended by NCCCI, based upon its Mall Intercept Study analysis.

Attachment E American Rivers draft low-impact Hydropower Criteria

This criteria was developed by American Rivers in cooperation with Green Mountain Energy Resources to identify hydropower plants with low environmental impacts.

Attachment F “Summary of the Denver Stakeholder Meeting Consensus”

This describes the Western states consensus approach to regional tracking of electricity in the western region, developed at a stakeholder meeting in Denver, Colorado.

Attachment G Draft “Memorandum of Understanding”

This document represents a voluntary agreement that may be adopted by states in the Western Interconnection to participate in a regional electricity tracking pilot in 1999.

Attachment H Draft “Western Interconnection Model Rule on Consumer Disclosure in Connection with Electricity Sales”

This document represents a very early draft of model rules, currently being developed through stakeholder discussions, to be used as a source document by states considering consumer disclosure in connection with electricity sales.

Chapter 4.0 SUMMARY AND ANALYSIS OF UNBUNDLED UTILITY COSTS

4.1 INTRODUCTION

The legislation required the electrical utilities to unbundle the costs of electricity service and submit cost reports to either the Auditor or the Commission⁷. The process of unbundling was defined in the legislation in Section 2 (2).

Except as provided in section 4 of this act, by September 30, 1998, every electric utility shall unbundle. At a minimum, an electric utility shall include in such unbundling the accounting treatment for generation and energy supply, delivery services separately identifying transmission, distribution, and control area services, metering and billing, customer account services, programs to support conservation or renewable resources other than hydroelectric power, fish and wildlife mitigation, general administration and overhead, and taxes; the functionalization of costs separately for generation and energy supply, transmission, distribution, and other; the classification of costs separately to include, but not be limited to, energy and capacity; and the assignment or allocation of costs separately to include, but not be limited to, residential, small commercial, industrial, and other. For the purpose of chapter . . . , Laws of 1998 (this act), as directed by the commission for an electrical company or the governing body of a consumer-owned utility, the electric utility shall use the data from either the cost study used to formulate the retail rates in effect as of the effective date of this act, or a more recent cost study.

Based on the cost reports submitted by the utilities, the Auditor and the Commission were directed to report to the legislature:

*(a) A summary of the cost studies submitted by electric utilities; [and]
(b) Observations regarding the consistency or lack of consistency among utilities in methods of classification, functionalization, and assignment or allocation, and in descriptions of unbundled costs; [...]
In the report, the commission shall also describe any issues arising from the cost studies and service quality and reliability reports submitted by electrical companies.*

Section 3 (2) (a) and (b).

This chapter fulfills these requirements by first describing key characteristics of the utilities required to prepare the cost reports and the process of workshops undertaken to establish data reporting formats. Next, the information ultimately reported to the Auditor and the Commission is summarized and examined in four ways:

- A general description of the purpose and limitations of utility “cost of service studies”.
- Statewide and utility-specific summaries of electric service costs by the functions specified in the legislation.
- Statewide and utility-specific summaries of the electric service costs by the customer classes specified in the legislation.

- Examination and discussion of consistency and comparability in the cost data and issues affecting consistency and comparability.

It is at least as important to emphasize what we cannot conclude from the information in these cost studies as it is to understand we can be learn.

4.1.1 WHAT CAN BE LEARNED FROM THE COST DATA?

These reports document the *current cost structure* of electrical utilities that are, in almost all cases, providing a bundled service to customers. As such, the data set of these 13 utility cost reports represents an unprecedented picture of the cost structure of current utility service in Washington. This is important and valuable information to assist in understanding the relative magnitude of costs for the various utility functions, as well as the consistency among utilities with respect to these costs. It also permits comparison of these costs in Washington with those seen elsewhere in the nation and across the western states.

4.1.2 WHAT CANNOT BE LEARNED FROM THE COST DATA?

These reports do not document what the cost, or appropriate pricing, would be for the separate utility functions or elements of service if these were provided as separate services. The cost structures of the utilities reflect the integration of all of the elements of utility service. The unbundling that these reports accomplish is the separation of the contribution that each of the elements of cost makes to the utility's total cost to provide a fully integrated service. The legislation was specific in its direction that:

For the purpose of chapter . . ., Laws of 1998 (this act), as directed by the commission for an electrical company or the governing body of a consumer-owned utility, the electric utility shall use the data from either the cost study used to formulate the retail rates in effect as of the effective date of this act, or a more recent cost study.

Section 2(2).

Nothing in chapter . . ., Laws of 1998 (this act) shall be construed as requiring an electric utility to establish new rates or to adopt new rate-making methods, or to require the commission to approve new revenue levels for electrical companies.

Section 6.

To assess the costs of providing the elements of utility service as separate services would require cost information fundamentally different from that used to formulate current retail rates, as well as an assessment of new rate-making methods and new levels of revenue⁸. The cost data included in these reports reflect all scale and scope economies that may be captured within a bundled service. They do not provide any direct measurement of the size of those economies, or whether they would be lost or enhanced if services were provided on a fully separate basis. Consequently, the cost data included in the utility reports and summarized in this report cannot be extrapolated or interpreted to accurately represent costs that might be experienced under retail utility service structures that differ from bundled service.

Finally, the Commission emphasizes that the cost studies and methods submitted by the electric companies meet the requirements for reporting purposes under this statute, but do not constitute an approved basis for new levels of revenue or new methods of allocating cost for the purpose of establishing rates.

4.2 BACKGROUND ON DEVELOPMENT OF STUDY FORMATS

The legislation required all large electric utilities to submit cost studies that disaggregate (unbundle) costs. At a minimum, the utilities were directed to separate accounting costs for (1) generation and energy supply, (2) delivery services, (3) metering and billing, (4) customer account services, (5) programs to support conservation and non-hydro renewable resources, (6) fish and wildlife mitigation, (7) general administration and overhead, and (8) taxes. In addition, delivery services were to be shown and separately broken down into transmission, distribution, and control-area services.⁹ Section 2 (2).

The large electric utilities required to report are Puget Sound Energy, the Washington Water Power Company, PacifiCorp, the municipal utilities of Seattle and Tacoma, and the Public Utility Districts (PUDs) of Clark, Cowlitz, Grays Harbor, Snohomish, Chelan, Grant, and Benton Counties. Electric companies (investor-owned utilities) were directed to submit reports to the Commission and consumer-owned utilities to the Auditor. All of the utilities filed studies on time in compliance with the legislation.¹⁰

The legislation specifically exempts utilities with 25,000 or fewer meters in service and companies with low densities from the reporting requirement. However, smaller utilities were encouraged to voluntarily file. Information in the standard format was reported voluntarily by the City of Richland. Certain state cooperative and mutual companies submitted two aggregate summaries of their cost information. The Richland data are included in the cost analysis made by the reporting agencies. The cooperative and mutual companies summaries are included in the Appendix in Attachments A and D.

The reports by consumer-owned utilities were submitted to their governing bodies by September 1, 1998, and were reviewed at an open public meeting. The studies were then filed with the Auditor by October 1, 1998. The reports by electrical companies were filed with the Commission by September 30, 1998, and were reviewed at a Commission open meeting on October 26, 1998. The purpose of the reviews by governing bodies and the Commission was to determine whether the filings met the requirements of Section 2 of the legislation, and to identify any disputed issues. In all cases, the governing bodies or the Commission found the reports to be in compliance with the requirements of the statute. The legislature allowed the Auditor to consult with the Commission; the Department of Community, Trade, and Economic Development, the electric utilities, and others to assist with analysis. Staff from the Auditor's office consulted extensively with staff of the Commission in preparation of this report.

The studies directed by HB 2831 were consistent and complementary with workshops already underway at the Commission.¹¹ 2831 passed with an emergency clause, and with an aggressive time frame for completion of this study. The Commission convened a series of facilitated workshops with the Auditor to work with stakeholders to design a common presentation format for the various cost studies. The electrical companies, the Washington Public Utility Districts Association, the Snohomish County PUD, Clark Public Utilities, the cities of Seattle and

Tacoma, Public Counsel from the Office of the Attorney General, competitive energy providers, and energy consultants worked together to find a way to present the information sought in the legislation.

During the months of April and May the stakeholders worked out a consensus concerning how the cost studies would be presented. Agreements included the summary formats for the cost studies. The formats show uniform general unbundled cost categories, identification of the appropriate rate class for specifically identified typical customers, a decision to utilize class breakdowns consistent with the rate schedules for each utility, and an agreement to utilize the type of cost study used to set rates for each company, whether it be an embedded or marginal approach. In addition to the general consensus that applied to all utilities, specific requirements for the electrical companies were derived.

A Commission letter dated July 1, 1998, directed the electrical companies to file at a minimum one cost study consistent with the Commission's Ninth Supplemental Order On Rate Design Issues in Dockets UE-920433, UE-920499, and UE-921262. The Washington Water Power Company and PacifiCorp were to use year ended December 31, 1997 data, while Puget Sound Energy was to use the year ended June 30, 1998. The June 30 period was chosen for Puget Sound Energy so that a full year of operation as a merged company would be shown. All of the electrical companies were to use data from their semiannual Commission basis reports filed pursuant to WAC 480-100-031. Cost of capital was to be based on the realized rate of return from the restated results, and assumed to be uniform across classes and functions. The companies were also allowed to file optional studies based on allocation principles of their own preference.

Several public utilities, including the Washington Public Utility Districts Association (WPUDA), participated in the workshops that established uniform formats for the cost studies. Upon completion of the workshops, the WPUDA sponsored a meeting between the Auditor and public utility districts to discuss the consensus reached in the workshops concerning the cost study formats. The parties discussed the legislative requirements and recommended formats for complying with 2831. To ease analysis, districts adopted principles and methods for filing their cost information consistent with those established in the workshops.

4.3WHAT IS A COST STUDY: PURPOSE AND MAJOR TASKS

It is important to understand that there is a difference between cost of service analysis (cost studies) and rate making. This bill deals with cost analysis -- not rate making. The process of cost of service analysis examines the causes of costs incurred by the utility to provide service to its customer classes. This is one important piece of information that goes into rate-making, but it is not the only consideration. By law, rates are to be established that are fair, just, reasonable, and sufficient. For the electric companies this involves judgment on the part of the Commission based on an evidentiary record that includes, but is not limited to, a cost study. The governing bodies of the consumer-owned utilities also establish fair, just, and reasonable rates based on cost studies and judgment. No cost study can be perfectly accurate, and therefore the process of rate making does not automatically fall out of the completion of a cost study for the investor-owned or the consumer-owned utilities.

All of the costs in the studies presented with this report are founded on historic costs. Some utilities use marginal costing studies to allocate costs to revenue requirements, some use projected test years, but all are based initially on historically incurred costs. There are other kinds of cost studies that are used to set prices in competitive environments, but none are presented here.

There is a basic framework for doing cost studies. Costs are first organized by function. The categories in section 2(2) of the bill represent functions. Next, costs are classified according to elements that cause them to vary by customer class. Finally, the costs are allocated or assigned to the customer classes according to the way the service to each customer class causes the elements of cost to be incurred.

In general, fully allocated cost studies divide total test-year investment base, and operating expenses among the various customer classes. Because many of these costs are either joint or common costs not directly attributable to any one particular customer class, they must be allocated using a formula that, however subjective, leaves no costs unassigned.

Since all fully allocated cost studies use inherently arbitrary allocation formulae, they do not (and cannot) establish direct cause-and-effect relationships between the consumption decisions of the class members and the costs incurred by the utility. Thus, the amount of “costs” shown in such a study does not necessarily reflect the actual costs that a particular group of customers imposes on the system. In fact, it is not possible, regardless of the amount of study done, to establish a perfect allocation of joint and common costs across utility functions and customer classes. The values developed in cost studies are approximations based on the best judgment of the utility and its governing body or the Commission.

While the basic framework applies to all cost studies, there is a great deal of art involved in applying it. Any cost study involves important assumptions, theories and judgement. The process is not automatic. In order to understand the cost analysis, one must understand the assumptions, theories and judgments made by the analyst who made the study. The utilities included documentation of their assumptions, theories, and judgments with their cost reports.

Finally, it is important to emphasize that 2831 does not require rates to be reset, or new revenue requirement levels to be established. It only requires that the underlying cost structure be analyzed and reported. The cost studies submitted do not establish new rates, rate making methods, or levels of approved revenue.

4.4 DATA REPORTED

4.4.1 SIZE OF REPORTING UTILITIES

Thirteen utilities submitted information to this study. These range in size from Puget Sound Energy to the City of Richland. Puget Sound Energy delivers 22.1 billion kilowatt-hours to approximately 865,000 electric customers in nine of Washington's counties. Puget Sound Energy electricity sales comprise 32 percent of the total sales for the reporting utilities. The smallest reporting utility is the City of Richland serving 722.7 million kilowatt-hours to its 17,000 customers. The City of Richland represents about 1 percent of the total sales of the reporting utilities.

In total the utilities submitting reports serve 2,246,000 customers and 69.5 billion kilowatt-hours. This represents 86% of Washington's total customers, and electricity sales. **Table 4.1** depicts the proportion of total reported electricity sales of each of the reporting utilities.

**Table 4.1 Utility Electricity Sales by Customer Class
(As Percent of Total Sales)**

	% of State Total	Residential	General Commercial	Large Commercial	Industrial
Benton County PUD	2.5	39.6	16.5	30.6	13.2
Chelan County PUD (1)	4.3	21.0	14.8	8.8	0.0
Clark Public Utilities	6.1	49.0	22.9	10.4	16.9
Cowlitz County PUD	6.2	16.1	6.0	6.1	71.6
Grant County PUD	4.3	22.2	27.6	6.6	43.4
Grays Harbor Co. PUD	1.5	51.8	8.1	25.7	14.1
Snohomish County PUD	9.1	52.3	31.5	2.6	13.1
PacificCorp	5.0	42.7	13.6	28.4	14.9
Puget Sound Energy	31.8	45.5	23.4	15.2	14.9
Washington Water Power	7.0	44.9	7.6	30.9	16.0
City of Richland	1.0	41.0	7.6	33.6	17.1
City of Seattle	13.3	34.5	37.3	16.3	10.9
City of Tacoma	7.8	34.0	5.9	29.8	29.8
Statewide (13 utilities)	100.0	39.8	21.2	16.3	19.6

(1) Chelan PUD Reported 55% of sales as sales for resale.

Note: Totals do not sum to 100% due to the small category of lighting services -- on average 0.5% of sales. Also, sales for resale for Chelan PUD are not included in table.

Table 4.1 demonstrates that, while the residential class generally accounts for the largest share of sales, some notable exceptions exist. For example, Cowlitz County PUD is dominated by industrial customer sales as is Grant County PUD. Chelan County PUD reported sales statistics dominated by sales for resale (this category is not included in the table). The utilities with the largest proportions of residential sales are Grays Harbor County PUD, Snohomish County PUD, Clark Public Utilities, Puget Sound Energy, and Washington Water Power. Those with the largest proportions of industrial class sales are Cowlitz County PUD, Grant County PUD, Tacoma Power, the City of Richland, and Clark County PUD. **Table 4.1** does not present statistics on lighting services. Lighting service sales account for about 0.5 percent of total sales across all the utilities. The range is 1.1 percent for Seattle to 0.1 percent for Chelan.

SECTION 4.4.2 WHO REPORTED AND WHAT WAS REPORTED

Each of the twelve utilities required to file, and the city of Richland, submitted a cost report to the appropriate agency. Each study submitted, excluding those provided by the cooperatives and mutual corporations, and the one provided by Cowlitz County PUD, included summary results in a format consistent with the consensus reached in the spring workshops.

While the workshops developed a consensus on a reporting format, there was no decision on how the studies were to be performed. Each utility selected a cost data “test period” consisting of a year. That period may have been an historic period or a projected one. In the case of Tacoma, the period was the average of two years. The allocation methodology used by each utility was the approach utilized by the jurisdiction in performing cost studies and subsequently setting rates.

The Washington Water Power Company and PacifiCorp filed two versions of their cost report. One was consistent with Commission directive, and the second used different allocation methods preferred by the utility. The summaries presented in this report are based on the Commission specified format. The alternative studies are included in the Appendix to section 4.0.

4.5SUMMARIZATION OF TABLES

The Commission and Auditor created two summary analyses of the raw data in the electrical utilities’ reports. The first is based on the categories set out in 2831, and is labeled the Legislative Summary. The second is a summary by customer class, using the broad customer class designations provided in 2831. It is labeled the Customer Class Summary.

4.5.1 LEGISLATIVE SUMMARY FORMAT REPORT

The first summary analysis performed focuses on the costs components (or functions) requested by the legislation. The analysis shows, for each utility, the dollars and resulting unit costs, by customer class for each cost component. Summary schedules showing each of the company’s total costs and compiled summaries showing the total for all reporting electric companies and consumer-owned utilities are also provided. These reports are included in the Appendix to Chapter 4.0, in Attachment B. From the summary schedule pie charts have been created for each company identifying the make-up by component of each company’s total cost. Individual company pie charts are included in the Appendix in Attachment A.

Table 4.2 displays statewide averages representing the total costs divided by the total loads of the thirteen utilities which filed reports. Because they are based on statewide total costs, these values are averages weighted by sales volumes. The table also shows the range of unit costs for each function. This presentation combines all service categories and customer classes. The categories shown are those designated by the legislation in Section 2(2). All costs are shown on a cents per kilowatt hour (kWh) basis unless otherwise noted.

Table 4.2 Statewide Average Cost of Utility Service by Function.

(Cents/kWh. Averages weighted by sales.)

	State Average (cents/kWh)	Proportion of Total	Range (cents/kWh)
Power Resource Costs:			
General Power Costs(1)	2.320	53.4%	0.927 to 3.229
Non-Hydro Renewable	0.033	0.7%	0.000 to 0.192
Fish and Wildlife Programs	0.059	1.4%	0.000 to 0.294
Control Area Services	0.087	2.0%	0.000 to 0.272
Total Power Costs:	2.498	57.5%	0.927 to 3.229
Demand-Side Management:	0.159	3.7%	0.000 to 0.268
Delivery Costs:			
Transmission	0.357	8.2%	0.009 to 0.723
Distribution	1.090	25.1%	0.095 to 1.540
Customer Account Services(2)	0.036	0.8%	0.000 to 0.198
Metering and Billing(2)	0.149	3.4%	0.040 to 0.276
Other(3)	0.053	1.2%	-0.061 to 0.322
Total Delivery Services:	1.685	38.8%	0.304 to 2.372
Total Cost:	4.342	100.0%	1.755 to 5.544
A&G in above(4)	0.382	8.8%	-0.117 to 0.703
Taxes in above	0.492	11.3%	0.083 to 0.817

(1) Includes owned and purchased power costs including A&G and taxes.

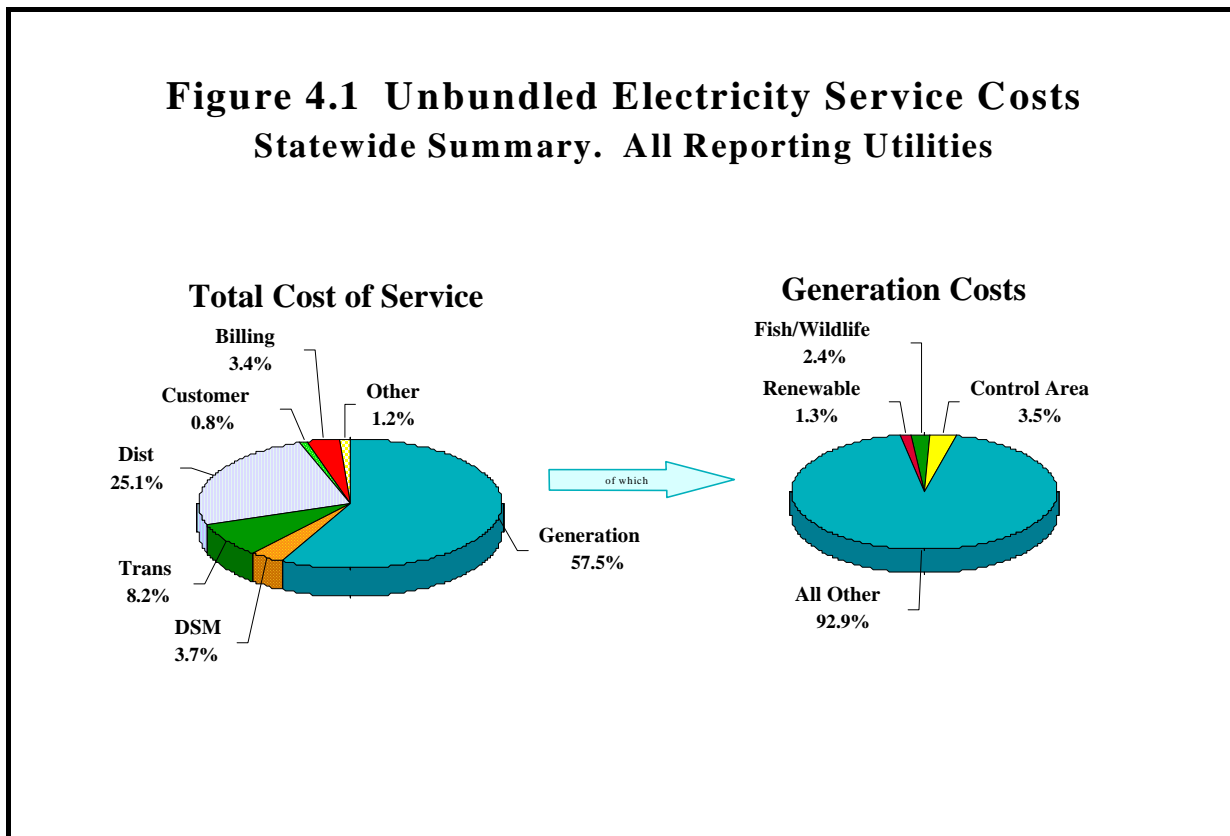
(2) Taxes and A&G included in Distribution.

(3) Negative values associated with sales for resale or other revenues.

(4) Negative value associated with Grant Co. PUD treatment of construction and A & G costs.

Figure 4.1 displays on a statewide basis, each of the categories designated by the legislature excluding Taxes and Administrative & General costs.

Figure 4.1



4.5.2 CUSTOMER CLASS SUMMARY REPORT

The second analysis performed focuses on costs by summary customer class, and by the functional costs identified in the legislation. Five basic functions are included: Power resources, Demand Side Management, Transmission, Distribution, and Other costs. The Administrative & General, and Taxes included in the five basic functions are also identified. This analysis allows comparisons to be made among general customer classes. The Commission and the Auditor developed these general classes by assigning service categories included in the utility reports into six general summary classes: residential, general service, large general service, high-voltage and extra-large general service, lighting service, and firm resale. The general service categories correspond to commercial, large commercial and industrial type service. Development and assignment of service categories was done by Commission and Auditor staff and was not provided by the companies. These class summaries are provided for each utility report, including the second reports of the Washington Water Power Company and PacifiCorp. This information is then summed by class for electric companies, consumer-owned utilities, and total reporting utilities. These summaries are contained in the Appendix in Attachment C.

Table 4.3 shows the costs for each utility by the five major functions. This presentation combines all customer classes. All costs are shown on a cents per kilowatt hour (kWh) basis unless otherwise noted. Anomalies in utility reporting are included as table notes.

Table 4.3 Cost of Utility Service by General Function Summarized by Utility.
(Cents/kWh)

	Total	Power Resource	DSM (4)	Trans.	Dist.	Other (5)	A&G (1)	Taxes (1)
Investor-Owned:								
Pacific Power and Light	4.876	2.443	0.055	0.724	1.613	0.042	0.666	0.763
Puget Sound Energy	5.544	3.230	0.262	0.553	1.481	0.018	0.462	0.774
Washington Water Power	4.801	2.551	0.268	0.382	1.359	0.241	0.703	0.817
Consumer-Owned:								
Benton County PUD	3.591	2.101	0.00(3)	0.526	0.892	0.072	0.510	0.238
Chelan County PUD	1.755	0.927	0.034	0.055	0.717	0.021	0.214	0.126
Clark Public Utilities	3.889	2.835	0.175	0.106	0.835	-0.061	0.170	0.236
Cowlitz County PUD	2.286	1.867	0.114	0.009	0.156	0.139	0.000	0.082
Grant County PUD(2)(6)	2.511	1.353	0.028	0.305	0.823	0.001	-0.117	0.168
Grays Harbor Co. PUD	4.572	2.328	0.204	0.319	1.399	0.322	0.362	0.262
City of Richland	3.743	2.483	0.171	0.014	1.008	0.067	0.136	0.486
City of Seattle	3.917	1.739	0.122	0.357	1.601	0.098	0.398	0.372
Snohomish County PUD	4.841	2.692	0.062	0.204	1.848	0.034	0.373	0.228
Tacoma Power	3.526	2.468	0.082	0.138	0.850	-0.012	0.396	0.415

(1) Administrative & General, and Taxes are included in the amounts shown in other columns.

(2) For consistency, Grant County PUD Control Area Services costs moved from transmission to power category.

(3) Does not include \$1.3 M conservation for BPA/ CARES programs reimbursed by BPA. Non-DSM public purpose in Other.

(4) May not include DSM expenditures of consumer-owned utilities related to BPA due to different treatment of BPA costs.

(5) Negative values due to crediting of power sales or other revenues.

(6) Negative value in A&G due to accounting treatment of construction costs and A&G.

Figures 4.2, 4.3, and 4.4 are comparative bar charts for each of the thirteen utilities displaying total unit costs and unit costs of Generation, Distribution, Transmission, Administrative & General, and Taxes.

Figure 4.2

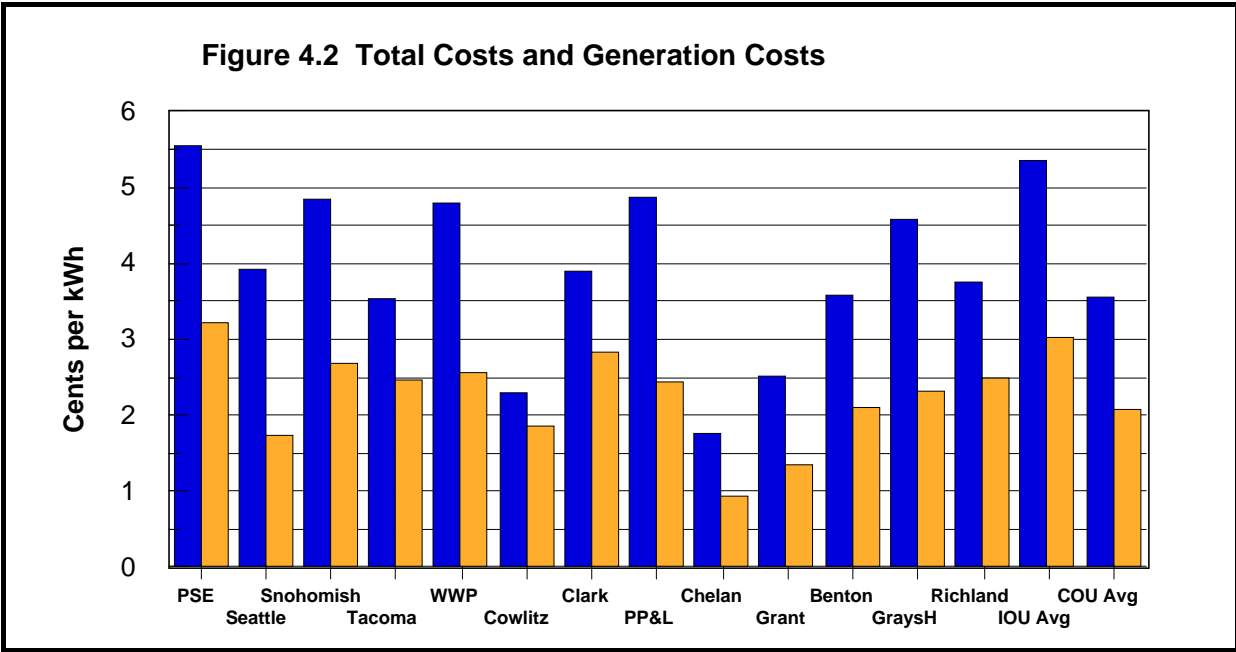


Figure 4.3

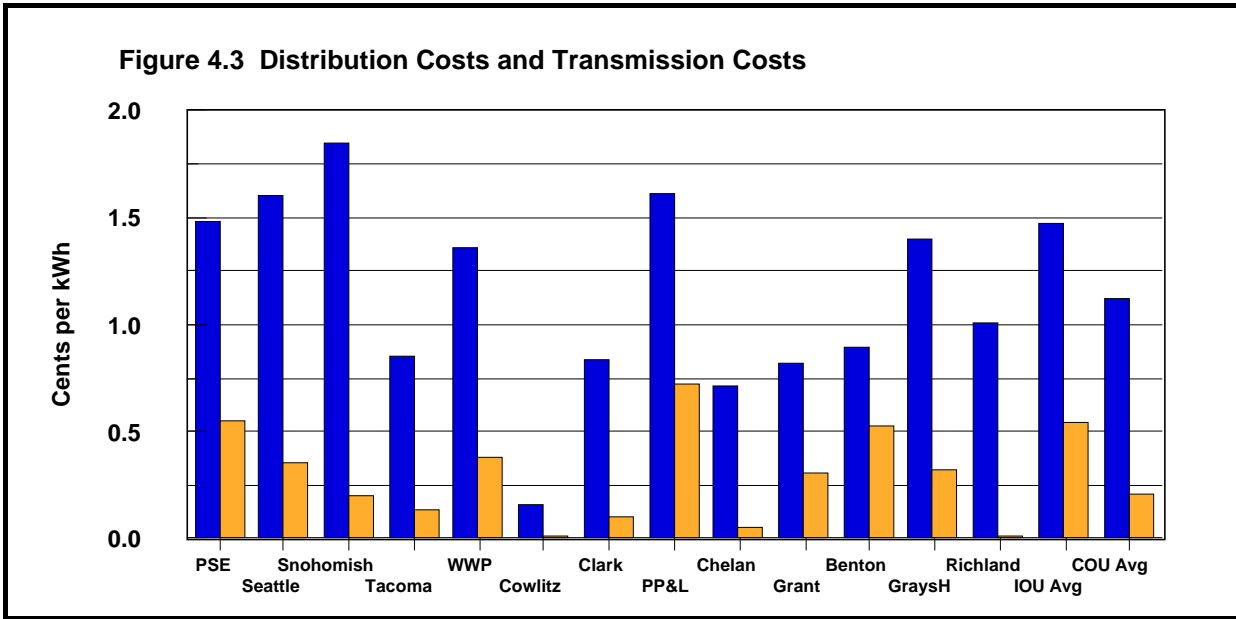
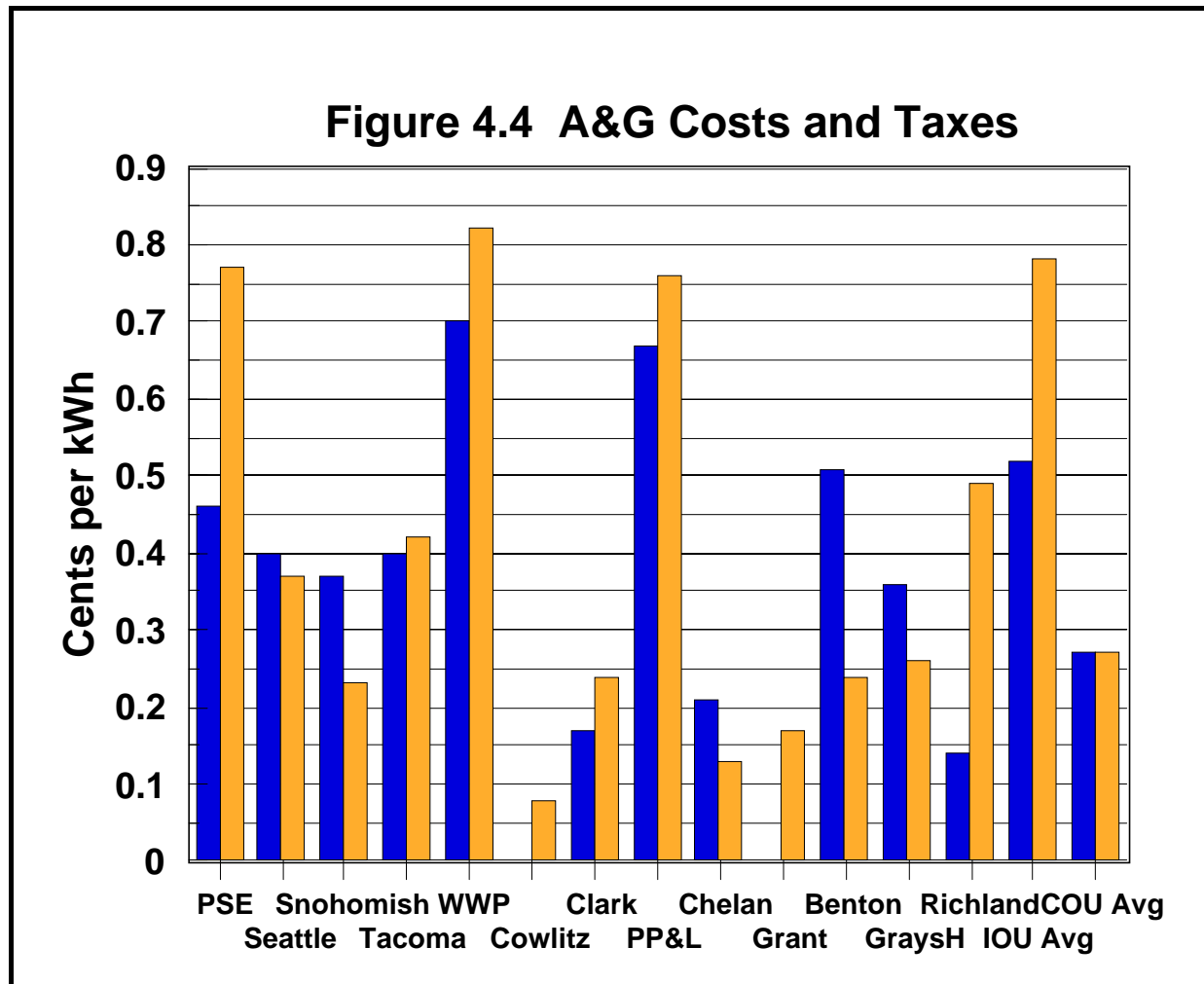


Figure 4.4

These charts demonstrate that there is significant variation in these costs between and among the



utilities. This variation stems both from differences in underlying costs and from differences in the assignment of costs to the functions. For example, some utilities pay for a substantial portion of transmission costs in the wholesale power cost rate charged to them by BPA.

Table 4.4 is a presentation of the Customer Class Summary report showing the unit cost by company and by general customer class for each of the utilities. Again, the customer classes were compiled by Commission and Auditor staff by combining rate schedules reported by the electric utilities into the larger customer groups identified in the legislation. Amounts are shown in cents per kilowatt-hour (kWh).

Table 4.4 Cost of Utility Service by General Customer Class Summarized by Utility (Cents/kWh)

	Total	Residential	General Commercial	Large Commercial	Industrial
Investor-Owned:					
Pacific Power and Light	4.876	5.641	5.155	4.189	3.601
Puget Sound Energy	5.544	6.292	5.478	5.074	3.695
Washington Water Power	4.801	5.241	5.244	4.438	3.739
Consumer-Owned:					
Benton County PUD	3.591	4.541	3.550	2.879	2.321
Chelan County PUD	1.755	2.720	3.008	1.837	NA
Clark County PUD	3.889	4.810	3.401	2.879	2.247
Cowlitz County PUD	2.286	2.602	3.418	2.929	2.059
Grant County PUD	2.511	3.506	2.975	2.020	1.746
Grays Harbor PUD	4.572	5.124	5.001	4.092	3.021
City of Richland	3.743	4.531	3.841	3.161	2.353
City of Seattle	3.917	4.370	3.823	3.447	3.287
Snohomish County PUD	4.841	5.578	4.540	3.638	2.602
Tacoma Power	3.526	4.417	4.427	3.342	2.488
Sales Weighted Average	4.342	5.310	4.490	4.000	2.780

4.6 CONSISTENCY IN THE COST DATA AND ISSUES AFFECTING CONSISTENCY

Cost data reported by the utilities reflect the costs each incurs to provide service to its particular mix of customers, with a particular set of power resources, within the geographic and other circumstances of its service territory. That these factors vary among utilities means that costs will vary as well. In addition, the reported cost may vary among utilities because of data reporting inconsistencies and differences in the methods of allocating costs to customer classes.

To examine magnitude and trends in this variation, **Table 4.5** presents the unweighted average of the costs reported by the utilities for three main functions, and for the four of the broad customer classes used in the data summary tables described earlier. The table also reports the average values for the ratio of class costs to the utility's total average costs (e.g., residential costs/utility average costs). For all of these figures, the table reports the amount of variation among the 13

utilities as the standard deviation and the coefficient of variation (the standard deviation divided by the average).

The total costs and functional costs show the greatest variation among utilities, generally between 27 and 42 percent. Variation in transmission costs is larger because utilities vary greatly in their reliance on transmission, ownership of transmission, and the way in which they pay for transmission service (i.e., some utilities pay for transmission as a part of bundled power service from BPA). Class level costs show less variation among utilities: 21 to 27 percent. The ratio of class costs to utility average costs shows the least variation of all: 11 to 21 percent. This demonstrates that while there is substantial variation in utility costs for power, distribution and transmission, there is less variation in the way in which those costs are allocated to the customer classes.

Table 4.5 Mean Values and Variation for Functional and Class Costs
(values not weighted for sales volumes) (n=13)

	Utility Average (cents/KWH)	Std. Deviation	Coefficient of Variation
Total Cost	3.835	1.124	29.3%
Functional Costs:			
Power	2.232	0.627	27.1%
Distribution	1.122	0.472	42.1%
Transmission	0.284	0.225	78.5%
Class Costs:			
Residential	4.570	1.096	24.0%
Small Commercial	4.140	0.879	21.2%
Large Commercial	3.380	0.922	27.3%
Industrial	2.760	0.685	24.7%
Ratio Class/Total:			
Residential	1.227	0.130	10.7%
Small Commercial	1.130	0.238	21.1%
Large Commercial	0.899	0.142	15.8%
Industrial	0.698	0.104	14.9%

Note: These values represent the simple average of utility costs. They are not weighted by sales volumes and therefore do not represent an average for the state. They are used here to examine variation among utilities, not the variability in a statewide average.

What variation does exist within the reported utility costs and within the ratio of class costs to average costs could be due to a number of inconsistencies in data reporting or in cost analysis and summarization methods. These may complicate interpretation and comparison of the cost figures.

4.6.1 DIFFERENCES IN COST ALLOCATION METHODS

As described earlier, the allocation process determines how much of the utility's total costs should be assigned to each customer class based on both direct assignment of costs and allocation of "common or shared" costs to customer classes. Many costs in the electric industry are shared between different classes including distribution lines and generating facilities. The

allocation process can be very complex, and contentious, which can lead to different class allocations for utilities with seemingly similar total and functionalized costs. With the exception of the three electric companies that all reported costs based on a single consistent method, each utility selected its own allocation methods and theories. There is no single correct method and the methods used by the utilities are not uniform.

This was a key issue discussed by the Legislature when the statute directing the cost reports be prepared was enacted. While it was known that differences in method existed, it was not known how much difference in allocated costs might be caused by these inconsistencies.

One concern raised by parties offering comments to the Commission on the utility cost reports is that the variation in costs by customer class among the utilities may vary more because of the allocation process than because of the underlying costs. **Figure 4.5** demonstrates how total costs and the allocation process affect the class cost for each utility.

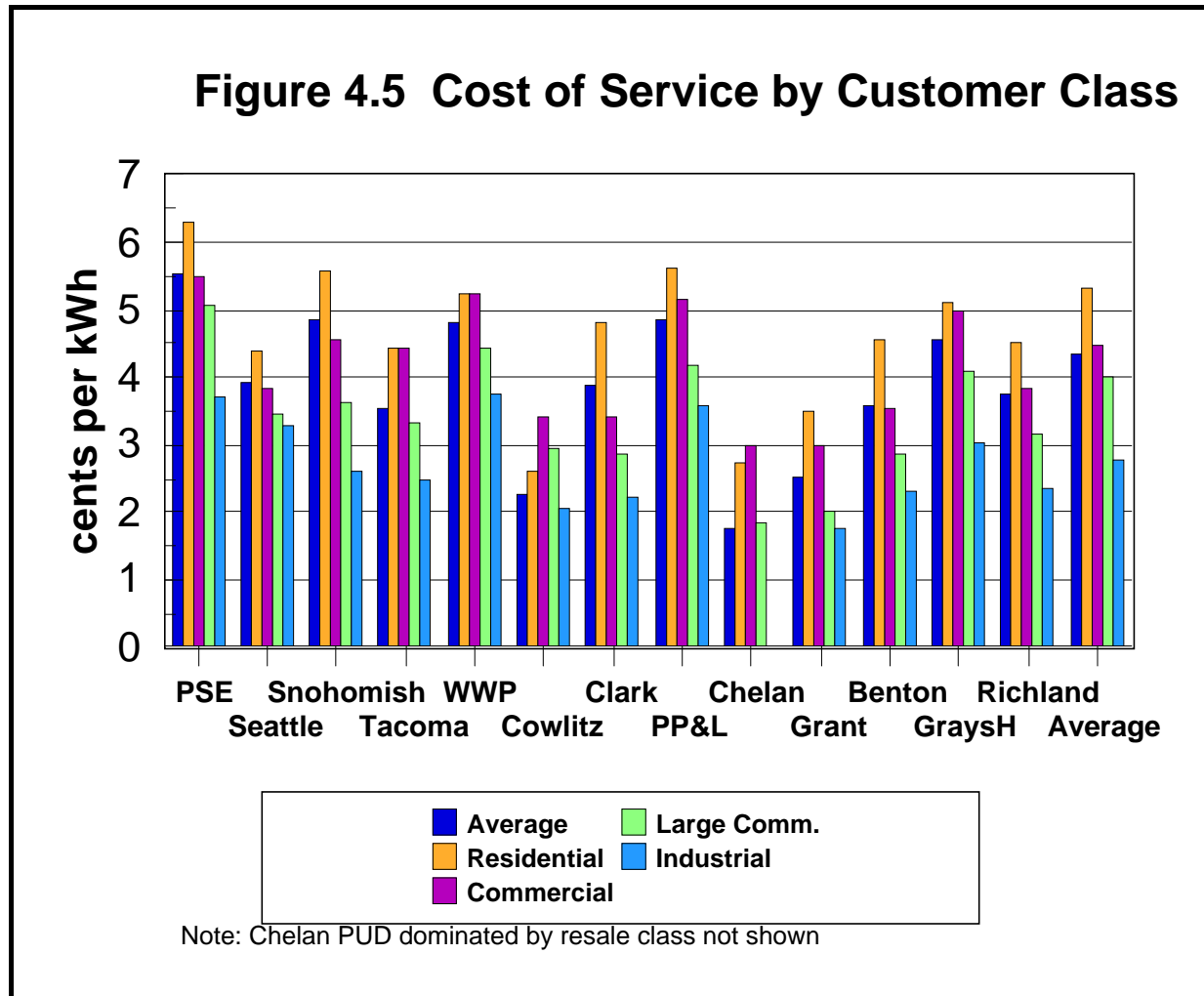
Typically, but not always, the residential class is allocated the highest total per kWh cost because of several factors including lower consumption per customer (resulting in higher customer costs per kWh), and greater seasonal diversity in usage pattern (which results in higher demand related costs on a kWh basis). High voltage, high volume customers generally display lower costs per kWh because they require fewer distribution facilities and have usage patterns that vary less across the seasons, resulting in lower demand costs per kWh.

Figure 4.5 indicates that the allocation process can affect the cost of a particular class of customer. While residential costs appear to be well correlated with average costs, i.e., a higher average cost leads to a higher residential cost, the same is not as true for the other classes. However, this figure indicates that, in general, the allocation methods yield similar results in class comparison between companies.

Table 4.6, examines this question based on a statistical analysis of the relationship between class costs and the average costs of power, distribution, and transmission for each utility. The statistical procedure used, known as analysis of covariance, isolates the amount of variation in class costs that is correlated with (or "explained by") variation in other variables. In this case the other variables are the utility's average cost for power, distribution and transmission.¹² The Table demonstrates that these basic cost factors explain a substantial proportion of the variation in class costs within the data set of 13 utilities. For residential class costs, variation in power, distribution, and transmission costs explain nearly all of the variance: 98 percent. For industrial and large commercial classes, a smaller amount of variance is explained, perhaps indicating a greater impact from inconsistency in allocation methods. The column headed "residual variance" indicates how much variance remains to be explained by factors other than power, distribution and transmission costs. For residential costs, this residual is very small: 1.9 percent. For the commercial and industrial classes it ranges between 22 and 33 percent.

Figure 4.5

This analysis indicates that, while there are surely differences in cost allocation methods and inconsistency in data reporting, the data set represented by these 13 utilities is remarkably coherent. Differences in class costs are well correlated with differences in utility average costs, particularly for the residential class.¹³ This finding is noteworthy given concerns expressed



during the development of the 2831 legislation and during the initial review and comment on the utility reports filed. The analysis suggests that establishment of uniform cost allocation principles might yield only modest benefits for data and cost analysis consistency.

Table 4.6 Proportion of Variation in Class Allocated Costs “Explained” by Utility Functional Costs (% of Variance)

	R ²	Power Cost	Distribution Cost	Transmission Cost	Residual Variation
Residential	.98	70.9	24.1	3.1	1.9
Small Commercial	.72	50.9	17.3	3.9(*)	27.9

Large Commercial	.78	61.2	12.1	4.5(*)	22.2
Industrial	.67	23.0	32.8	11.5	32.7

R^2 = Proportion of variance explained by analysis of covariance (ANCOVA) using power cost, distribution cost, and transmission cost as independent variables. ANCOVA based on unweighted data from 13 utilities. (*) - not statistically significant at .90 level.

4.6.2 COST DATA INCONSISTENCIES

Besides allocation methods, inconsistencies in other factors could affect the comparability of the cost data reported. The utilities submitted cost-of-service studies based on their selection of annual data. There are differences in the year selected and whether the study is historical or forward looking. Another important difference is the “normalization” of the data, whereby the utility adjusts the cost data to take into account such factors as weather and nonrecurring, or abnormal costs. The normalization methodologies used were not reviewed and critiqued by the staff; however, they historically have made only minor differences. The issue of estimated secondary power sales prices as an input to the normalization process for the electric company reports was raised during comments to the Commission. This information was requested from the electric companies and has been included in Data Appendix E.

Many of the utilities have excluded municipal taxes from their studies, as these costs may be directly assessed to customers. Exclusion of these taxes could impact total cost by as much as six percent. Finally, the data do not necessarily represent current expenditures. For example, the Puget Sound Energy and the Washington Water Power Company reports indicate Demand Side Management cost of 4.7 and 5.6 percent respectively. These costs represent more than current expenditures. They also include the capital costs, return, and amortization of expenditure capitalized in prior years.¹⁴ Other utilities have not capitalized Demand Side Management expenditures and therefore their costs only include current expenditures.

4.6.3 DIFFERENCES IN CUSTOMER MIX AND SERVICE TERRITORY CHARACTERISTICS

The customer mix can affect the total cost, since the cost of serving the different customer classes can vary greatly. For example, the needs and seasonal demands of the residential class are different than the requirements of the large industrial class. **Table 4.1** shows that Cowlitz County PUD has a relatively small residential class and a large high-voltage class, while Snohomish County PUD has a large residential class with a small high-voltage class. The different customer mix of the utilities can directly affect the way a utility incurs cost to serve its customers, and the allocation process discussed above.

4.6.4 INCONSISTENCIES IN SUMMARIZATION FOR REPORTING PURPOSES

Utility accounting practice requires hundreds of Federal Energy Regulatory Commission accounts. For this cost-of-service report each utility had to summarize those hundreds of accounts into the seven categories required; these categories are not always consistent with the functional allocation process used within their detailed cost studies. Utilities with the same cost allocations could summarize their accounts differently, which would contribute to different unit costs by function. Some major differences include:

- Some utilities separated their BPA bills to display costs incurred by BPA for Fish and Wildlife mitigation, and for DSM and renewable resources.
- Most utilities allocated all taxes to the various functional categories including the state utility tax, but some treated taxes differently. Some did not allocate taxes across the functions. Still others did not allocate state utility tax across the classes. In those cases taxes were included in the “other” category.
- One utility treated its cost of providing energy to its large industrial customers as “other”, because it is a separate contract, rather than as a general power resource.
- And, some utilities put uncollectible expense in the “other” category while others included it in “customer-service costs.”

These are examples of differences in how the allocated costs were displayed in the summary formats presented with the studies. For the most part, these differences do not affect the allocation of costs to the classes and, therefore, do not impact the total cost by class shown in the summaries.

4.7SUMMARY

The 12 utilities required to submit unbundled cost reports to the Commission or the Auditor did so, and did so in a manner consistent with the direction of 2831. These reports provide an analysis of costs and not rates. Moreover, the interpretation of the data included in the reports must be limited to examining the cost structure for utilities providing a bundled service. These cost data do not (and cannot) represent the costs that might be incurred to provide each of the functional services to each of the classes on a stand-alone, unbundled basis. Comprehensive data with which to evaluate stand-alone costs for unbundled services for each of these utilities would need to include long-run incremental costs.

The information included in the reports indicates that both functional and class costs vary among the utilities. Some of this variation is due to data inconsistencies and differences in cost allocation methods. When the data set of 13 utilities is taken as a whole, the allocation of costs to customer classes is strongly correlated with the underlying costs for power, distribution, and transmission. However, when customer class costs for any two utilities are compared, differences in allocation methods may be as important as differences in underlying costs.

Based on statewide, sales-volume-weighted averages covering the 13 reporting utilities, total cost of electricity service in Washington is 4.342 cents per kWh. Of this total, 57.5 percent is power resource costs, 25.1 percent is distribution system costs, 8.2 percent is transmission system costs, and 3.7 percent is contributed by past and current conservation programs. The remaining 5.5 percent is made up of customer service, metering and billing, and other costs. Although not required by statute, Washington's cooperative and mutual electric utilities also reported cost data. These data were reported in a format different from that used by the 13 large utilities and, while included in the data appendices, are not included in the averages stated above.

4.8 CHAPTER 4.0 APPENDIX

Table of Contents

Attachment A Pie Charts

These pie charts are the graphical depiction, by company, of the proportion of each company's total costs represented by the functional components listed by the legislature. Note that Taxes and Administrative & General costs are excluded: they are rolled into the other functional categories. Negative numbers cannot be shown in the Pie Charts. Tacoma Power and Clark Public Utilities each have negative totals for "Other," which slightly adjusts the percentages shown in the Pie Charts for the rest of the categories. This attachment includes the charts provided by the cooperatives and mutual corporations.

Attachment B Legislative Format Tables

These tables separate costs into the functions listed in 2831. The highest level shows summary costs for the total state, electrical companies, and consumer-owned utilities. Next is a summary of the total cost for each electric utility on a total company basis. Finally, for each utility including both studies submitted by the Washington Water Company and PacifiCorp, the data is displayed for each class identified in each company's cost study.

Attachment C Summary Class Tables

These tables show costs by summary class for the five functions identified in the workshops. The categorization into summary classes was done by the commission and Auditor staff. These reports include a statewide summation, and summation for consumer-owned and investor-owned utilities. These tables also include a table for each utility study submitted, including both studies submitted by the Washington Water Power Company and PacifiCorp.

Attachment D Summary Data Submitted by the Utilities

These schedules are the summary data submitted by each of utilities as agreed upon in the workshops. This does not include the detailed studies or the documentation submitted by the ¹⁵utilities. For Cowlitz County PUD, and the cooperatives and mutual corporations, summary information is included from their reports.

Attachment E Electrical Company Power Cost Documentation.

The Commission asked each of the electrical companies to submit documentation regarding determination of normalized power costs. The estimates of secondary power costs provided in response to that request are included here.

ENDNOTES

1. (1) "Commission" means the utilities and transportation commission.

(2) "Conservation" means an increase in efficiency in the use of energy use that yields a decrease in energy consumption while providing the same or higher levels of service. Conservation includes low-income weatherization programs and programs that result in overall reductions of electrical system requirements.

(3) "Consumer-owned utility" means a municipal electric utility, an electric cooperative, a public utility district, an irrigation district, a port district, or a water-sewer district that is engaged in the business of distributing electricity to retail electric customers in this state.

(4) "Control area services" means scheduling, reactive power, spinning reserves, nonspinning reserves, voltage control and regulation, load following, and other related services necessary to sustain reliable delivery of electricity.

(5) "Delivery services" means the services needed to deliver electricity to a retail electric customer using transmission, distribution, and related facilities. Delivery services include control area services, and the real property upon which the delivery plant, equipment, and other delivery infrastructure is located.

(6) "Electric cooperative" means a cooperative or association organized under chapter 23.86 or 24.06 RCW.

(7) "Electric meters in service" means those meters that record in at least nine of twelve calendar months in any calendar year not less than two hundred fifty kilowatt hours per month.

(8) "Electrical company" means a company owned by investors that meets the definition of RCW 80.04.010 and is engaged in the business of distributing electricity to more than one retail electric customer in the state.

(9) "Electric utility" means any electrical company or consumer-owned utility as defined in this section.

(10) "Electricity" means electric energy, measured in kilowatt hours, or electric capacity, measured in kilowatts.

(11) "Governing body" means the council of a city or town, the commissioners of a municipal electric utility, an irrigation district, a port district, a water-sewer district, or a public utility district, or the board of directors of an electric cooperative that has the authority to set and approve rates.

(12) "Irrigation district" means an irrigation district authorized by chapter 87.03 RCW.

(13) "Municipal electric utility" means a utility providing electrical service that is operated by a city or town as authorized by chapter 35.92 RCW.

(14) "Port district" means a port district within which an industrial district has been established as authorized by Title 53 RCW.

(15) "Public utility district" means a district authorized by chapter 54.04 RCW.

(16) "Renewable resources" means electricity generation facilities fueled by: (a) Water; (b) wind; (c) solar energy; (d) geothermal energy; (e) landfill gas; or (f) biomass energy based on solid organic fuels from wood, forest, or field residues, or dedicated energy crops that do not include wood pieces that have been treated with chemical preservatives such as creosote, pentachlorophenol, or copper-chrome-arsenic.

(17) "Retail electric customer" means any person or entity, including, but not limited to, a residential, commercial, or industrial customer, that purchases electricity for ultimate consumption and not for resale.

(18) "Small utility" means any consumer-owned utility with twenty-five thousand or fewer electric meters in service, or that has an average of seven or fewer customers per mile of distribution line.

(19) "State" means the state of Washington.

(20) "Unbundle" means to separately identify, and publish the accounting, functionalization, classification, and assignment or allocation of the costs of electrical service.

(21) "Water-sewer district" means a water-sewer district authorized by Title 57 RCW. Section 1, E2SSB 2831, 1998.

2 . Avista Utilities as of January 1, 1999.

3 . One utility reported it did not track such information. Another utility does not continuously track such information and provided the latest data, which were from 1993.

4 . One utility reported the average customer experienced 8.3 interruptions. These data were for 1993 and include momentaries, which most utilities do not report. A second utility also reported momentaries and a SAIFI of 2.0. Times of interruption for these two utilities were not included in the calculation of a state average.

5 . See discussion in report to be delivered to 1998 Legislature by WUTC and CTED under direction of SB 6560.

6 . See discussion in report to be delivered to 1998 Legislature by WUTC and CTED under direction of SB 6560.

7 . As in the sections addressing service quality and reliability, the legislation required the consumer-owned utilities to report to the Auditor and the electrical companies (investor-owned utilities) to report to the Commission. The legislation exempted certain utilities from this requirement based on size or customer density.

8 . For the most part, these studies include the current costs of the identified functions, they do not include the long run incremental cost of providing these services on a prospective basis.

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- 9 . The participants in the facilitated work sessions decided that control area services were more properly included in Generation, not Transmission.
- 10 . All utilities filed complete studies consistent with a standard format except Cowlitz PUD. Cowlitz filed cost information in its own format. This format did not make clear whether and how general and administrative costs and taxes were included and allocated to the customer classes.
- 11 . In its February 11, 1998, open meeting, the Commission decided to develop Interpretive and Policy statements concerning unbundled cost study methodologies in Docket UE-980181. The Commission invited interested parties to participate in a collaborative workshop, and then report back to the Commission. Interested parties entered into a series of workshops. Puget Sound Energy was required by the Commission's order approving the merger of Puget Power and Washington Natural Gas to undertake an unbundled cost study. Washington Water Power had agreed to participate in the PSE proceeding. HB 2831 ensured that all three investor-owned utilities developed unbundled cost studies on a consistent basis and time frame.
- 12 . Multiple Regression and the Analysis of Variance and Covariance. Edwards, Allen. W. H. Freeman and Company, San Francisco, 1979.
- 13 . It is important to note that the analysis reported in Table 4.6 examined the differences among class allocated costs for all 13 utilities. Comparisons between any two specific utilities could be more seriously affected by inconsistencies in factors other than power, distribution and transmission costs than is the case for the data set as a whole.
- 14 . This practice of capital financing for conservation has largely been discontinued.